The United States Department of Energy

Guidelines for Voluntary Greenhouse Gas Reporting and Registry

Industry Context

The American Petroleum Institute (API) appreciates the opportunity to offer input to the United States Department of Energy (US DOE) on the Interim Final Guidelines and the Draft Technical Guidelines for enhancing the voluntary reporting and registry of entity greenhouse (GHG) emissions and emission reductions.

API represents more than 400 companies involved in all aspects of the oil and natural gas industry that are interested in the successful implementation of this voluntary program. API has previously provided feedback to the US DOE during the previous public workshops and will continue to be an active participant throughout the process. In the preparation of these comments API is relying on its extensive experience with the development of the “Petroleum Industry Guidelines for Reporting Greenhouse Gas (GHG) Emissions” (December 2003); API “Compendium of Greenhouse Gas Emissions Estimation Methodologies for the Oil & Gas Industry” (Revised edition, February 2004); and ISO 14064 (Draft International Standard, January 2005) through its participation in the expert ‘Cadre’ of the US Technical Advisory Group (TAG) to the International Standards Organization (ISO).

API appreciates all the effort the DOE and the entire interagency task force have put into addressing previous concerns and developing this enhanced voluntary reporting program. The API comments below are provided in an attempt to help improve the usefulness of the guidance and to maintain a balance between flexibility and rigor that will make it credible while not overburdening companies and other entities that would like to report emissions and register emission reductions.

Key Overarching Issues

API provides in this section a summary of the main overarching issues for DOE’s consideration. DOE has made some notable, and welcome, changes to the previously proposed General Guideline yet remaining issues regarding the program structure, as proposed in the March 24, 2005, Federal Register publication of the Interim General Guidelines, are provided below. API is also highlighting some concerns with the technical program elements, based on its review of the newly released Draft Technical Guidelines.

To further aid in this review process, API is providing (as attachments) specific case study examples that are based on its real world experience with some of the highlighted technical issues and will welcome the opportunity to discuss this further with the DOE in order to improve the guidelines and make them consistent, as much as possible, with other methodological frameworks.

In the sections that follow, API provides further elaboration of these and other issues, along with specific recommendations that are linked directly to chapters and numbered sections of the guideline documents reviewed.

Program Structure

1. **Guidance versus Regulations -** There is a **potential conflict** between **voluntary reporting** in accordance with these recently proposed “Guidelines”, and the intended publication of the Guidelines in the Code of Federal Regulations (CFR) with all the trappings of a binding **regulation.** Indeed, DOE

explicitly refers in many places in its March 24 notice to the Interim Final General Guidelines as "rules" (e.g., 70 FR 15176-77). Furthermore, the Guidelines themselves contain many provisions that clearly intend to impose mandatory requirements on reporting entities, notwithstanding that the initial decision to report is voluntary.

There is a fundamental distinction between **"guidelines"** (or guidance), which **by definition are not binding**, and substantive "regulations," which by definition impose binding requirements. Notwithstanding that Sec. 1605(b) itself only authorizes "guidelines" and not regulations, DOE appears to be blurring the distinction between guidelines and rules here, and is creating some sort of hybrid that purports to be voluntary and non-binding in some respects and yet mandatory in others (see, e.g., 70 FR 15186). The "quasi-regulatory" nature of the General Guidelines" may both exceed DOE's statutory authority and cause future confusion on the part of potential participants under the 1605(b) voluntary GHG reporting program. Such confusion is exacerbated by DOE's ambiguous statement in the March 24 Federal Register notice that publishing the General Guidelines in the CFR "does not affect their nature as substantive or procedural or legally binding or non-binding." (70 FR 15177)

2. **Incorporation of Technical Guidelines by Reference -** API believes that there is substantial confusion regarding the incorporation by reference of the Technical Guidelines into the interim final General Guidelines. Although the March 24 Federal Register notice of the interim final General Guidelines, and interim final section 300.13 itself, refer to incorporation of the "Draft Technical Guidelines," it is unclear whether DOE intends that the final General Guidelines will actually continue to incorporate the Draft Technical Guidelines as they existed on March 24, even though those draft Technical Guidelines are still open for comment and likely will be revised. In fact, the March 24 preamble to the interim final General Guidelines (70 FR 15170-15171) strongly suggests that DOE intended to finalize the Technical Guidelines and make any appropriate revisions to the interim final General Guidelines simultaneously, after public comments on both the Draft Technical Guidelines and the interim final General guidelines and before the effective date of the General Guidelines. Moreover, the preamble (70 FR 15171) expressly states that the Draft Technical Guidelines, "when final, will provide the specifity necessary" to implement sections 300.6 and 300.8 of the General Guidelines. Indeed, it would not be logical for the General Guidelines to continue to incorporate the Draft Technical Guidelines of March 2005 after the Technical Guidelines have been revised and finalized. Finally, section 300.13 by itself adds to the confusion by referring to Draft Technical Guidelines dated "August 4, 2004," rather than the draft made available for comment on March 24, 2005.

   Accordingly, DOE should revise the General Guidelines to further clarify its intentions and address the potential differences that might exist between the Draft Technical Guidelines and the final Technical Guidelines. In particular, DOE should clarify that it intends for entities to use the final Technical Guidelines once they are finalized. DOE should also explain the process of incorporating these final Technical Guidelines, once they are revised after the public comments process, if the General Guidelines take effect prior to finalizing the Technical Guidelines.

3. **Relationship to Climate Vision Commitments –** API appreciates the efforts by DOE to harmonize numerous programs under a single reporting system. In this effort, it is important to distinguish between reports required under the newly revised Guidelines, and reporting that was agreed to prior to the issuance of the revised Guidelines (e.g., under Climate Vision). In the preamble to the Interim Final Guidelines for the enhanced voluntary GHG reporting and emission reductions registry, DOE states (70 FR 15171) that "once the revised General and Technical Guidelines take effect, the **1605(b) program** will serve as the primary public emission and emission reductions reporting mechanism for participants in **EPA's Climate Leaders** program and in **DOE's Climate VISION** Program." Although DOE is responding to many comments about the need for consistency among federal programs, its inclusion of

the commitments made by industry trade associations to report under the Climate VISION program is not compatible with the detailed requirements DOE is imposing in its rules for **aggregators**.

Under section 300.7(d), DOE spells out detailed requirements for **data aggregators,** including the provision of detailed entity statements for the parties included in the reports and appropriate certifications similar to those that would be required if the individual parties were reporting directly. DOE ought to clarify that reporting under the Climate VISION Program does not fall under the same provisions as those for aggregators under the revised Guidelines, unless the reporting industry association voluntarily chooses to register net emissions reductions on behalf of its members and to obtain a certificate to that effect from the EIA under the Guidelines.

4. **Timing of General and Technical Guidelines -** The technical guidance for **registering GHG emission reductions** is somewhat confusing and incomplete in several sections. Moreover, there is no "real world" experience with the application of the new methodology in the Guidelines to real entities and projects. Therefore, DOE is strongly urged to consider adopting **a different timeline** for continuing to develop and implement the enhanced Voluntary GHG Registry by **decoupling** the guidance for **reporting** GHG emissions from the **registration of GHG emission reductions**.

   Adopting different timelines for revising and finalizing Chapters 1 and 2 of the Draft Technical Guidelines will permit DOE to start implementation of the Technical Guidelines for entity emissions inventorying methods, while additional work will be undertaken to address some notable issues in the emission reductions calculations. This will allow entities to undertake reporting of their inventories, using Chapter 1 of the new Technical Guidelines, while they 'road-test' proposed approaches for calculating GHG emission reductions (Chapter 2). This shared experience would provide essential input for creating a robust yet practical protocol for different emission reduction scenarios and relevant methodologies.

5. **Definition of Entity** – API appreciates DOE's effort to maintain flexibility for reporters in defining reporting entities. We would like to note, however, that the current definition of **entity** might be challenging to some global corporations. In several companies, the legal structure of operating divisions is by product line and not necessarily by country, which might deter entities from defining themselves at the highest level of aggregation in order to avoid the burden associated with breaking down their internal GHG emissions reporting structures by national country boundaries, if this is not already their practice.

   In addition, the DOE language, especially intermingling the terms **entities** and **subentities,** might lead to an uneven playing field. It seems that the ability of entities to obtain registered emissions reductions will depend on the different legal constructs of entities in the same industry sector. For example, a vertically integrated Oil & Gas company that decides to define itself at the highest level that includes production, refining and marketing subentities might have more of a barrier for registering net GHG emission reductions than, for example, competitors that either only operate refineries or elect to merely register their refining subentity.

5. **Basis for Defining Entities -** The DOE states that entities should use **financial control** as the primary basis for determining their organizational boundaries, although it recognizes that other approaches such as **equity share** or **operational control** may also be used, provided the entity discloses how these definitions differ from financial control. We appreciate the flexibility to use the other approaches, particularly since several companies have developed inventories using these other definitions. We would like to note that the financial control approach is not consistent with other guidelines that emphasize the use of either operational control or equity share (i.e., WRI GHG Protocol, IPIECA Petroleum Industry Guidelines, EPA Climate Leaders, California Climate Action Registry). These other guidelines are already widely used by U.S. entities and globally, and many companies have already defined their

inventory boundaries and internal reporting procedures to be consistent with this prevalent guidance. If a company were required to adopt a financial control definition after developing an inventory under other definitions, it would be burdensome, reduce transparency and could create “two sets of books” in some parts of the world. We request that DOE consider maintaining consistency with other federal, state and international programs, or else provide a compelling reason and rationale for making the financial control approach its preferred benchmark.

6. **De Minimis Definition -** In the Interim Final Guidelines of March 24, 2005, DOE has removed the total emissions cap from its definition of **De Minimis emissions**, while retaining the 3% cut-off. While we appreciate removal of the total emissions level, API would like to note that the definition selected by DOE is not consistent with other protocols that are widely used in the U.S. and globally. For example, the Chicago Climate Exchange, the EU Emissions Trading Scheme, and the California Climate Action Registry have adopted a 5% definition for insignificant emissions. Moreover, the EPA Climate Leaders, the WRI GHG Protocol and the IPIECA/API Petroleum Industry Reporting Guidelines invoke the concept of “**materiality**” to allow companies to define specifically what GHG emissions might be De Minimis within the context of their operations.

   It should be recognized that the accuracy of GHG estimation, measurement and monitoring methods varies widely among sectors and for certain operations, and it is not realistic or practical to attempt to quantify all emissions to within a 3% insignificance threshold. Therefore, it is recommended that DOE consider either a 5% De Minimis level or the use of the materiality concept as delineated in the referenced protocols above.

   In addition, DOE should consider making provision for accepting industry studies that would serve as a 'once for all' determination of De Minimis gases and sources for industry sectors. For example, the petroleum industry has conducted a study that indicates that fugitive methane emissions from refineries are well below De Minimis for U.S. refineries. This type of determination would improve the efficiency of the program and transparency of inventories while lessening the burden on individual reports to repeat the same De Minimis determination.

7. **Deadline and Timing -** The **yearly deadline of July 1st** for reporting entity inventories seems to be a carry-over from the existing 1605(b) program. In the context of the enhanced program, and with DOE’s encouragement to companies to have their inventories and GHG emission reduction calculations verified by an independent 3rd party, it is not clear what are the specific elements that would need to be completed prior to the July 1st date and what are the specific drivers for imposing such a deadline. In practice companies do not engage a **3rd party** for inventory **verification** on a yearly basis, but rather on a **two-to-three years** rotating schedule for increased efficiency and cost effectiveness.

   API requests that DOE elaborate on the **process (and timeline)** that is envisioned for each step of the process and allow the needed flexibility for submitting inventories, GHG reduction calculations, certifications and verifications. In each of these steps of the enhanced program, special consideration should be given to the burden on companies’ resources as well as DOE’s ability to review the submissions in a timely manner. The Guidelines should make specific allowance for undertaking periodic verification of multiple inventory years, as well as reporting **in a later year** either new or amended data that were missed at the previous year’s deadline.

8. **Extensions of Reporting Deadline -** DOE ought to consider the dynamic nature of company’s structures and business activities, including **mergers, acquisitions or divestitures,** which may take additional time to reconcile the new structure and incorporate all the new sources**.** Therefore the General Guidelines should recognize the potential **need for extension of the reporting deadline** under certain circumstances, such as when major business changes occur. It particularly needs to also make provisions

for extending the reporting timeline if the DOE (EIA) review/response is delayed for more than 6 months and that review/response necessitates revisions to the reported inventory.

Technical Program Elements

9. **Quality Ratings -** The practical application of quality ratings in the DOE Draft Technical Guidelines seem overly restrictive for many industry sectors. Specifically, the assignment of a C ratings to all "default emission factors based on general activity data." For many sectors these are the most common emission estimation approaches used and it would take considerable R&D to develop new entity-specific factors. These situations should be treated in a manner similar to agriculture and forestry sectors, where the guidelines recognize that monitoring and/or development of specific emission factors is not practicable, and assign an "A" quality rating.

   API also notes that the Draft Technical Guidelines use the terminology "**mass balance approach**" in an inconsistent manner in different chapters and tables. The mass balance approach should consist of methodologies that use the basic concept of preservation of mass, i.e. quantities in = quantities out. In cases where the mass is based on measured process data, the results should be assigned an "**A**" quality rating.

   API would like also to encourage DOE to recognize in the General and Technical Guidelines that independent 3rd party review could also be used to verify the validity and quality of the emissions estimation approach used. This could be an option that is open to reporting entities in lieu of the strict definition of an average quality rating of 3.0 for enabling registration of GHG emission reductions.

10. **Indirect GHG Emissions –** The built-in **inconsistency** in treating indirect CO_2 emissions between the **inventory guidance** and the **emissions reduction** guidance is confusing and creates unnecessary burden. DOE should decide on one consistent approach for all reports, either "an approximation of the average emissions intensity of U.S. electric power generation in a recent year" or the use of average emission rates by NERC regions, where CH_4 and N_2O emission factors are also provided. DOE should also specify the frequency for updating the emission factors.

    Furthermore, the guidance provided for **indirect emissions outside the U.S**. is not adequate. First, the most recent version of the world energy outlook (WEO) report is available only through purchase from IEA. Second, the 2002 WEO states that CO_2 emissions per unit of electricity generated includes CO_2 emissions from heat production. It might be better for DOE to reference Table 4.13 of the API Compendium (February 2004), which is titled, "International Electric Grid Emission Factors Average of 2000 – 2002 Data (Generation Basis)". That table provides a ready reference for 'electricity generation only' emission factors for most, if not all, countries of interest.

11. **Line Losses -** The Technical Guidelines recommend incorporation of **line losses** into the estimates of indirect **GHG emissions from electricity** and accounting for emission reductions. These losses should be accounted for by the owner/operator of the transmission and/or distribution lines. Only losses that occur downstream of the customer meter should be included in the customer's inventory. Both WRI/WBCSD and the California Climate Registry have reversed their decision on this matter and no longer assign line losses to customers. Line losses should be accounted for as direct emissions by the owner/operator of the transmission and/or distribution lines. Line losses that occur downstream of the customer meter should be included in the customer's inventory as indirect emissions. It is only in reporting "other indirect" emissions that line losses would be considered from the customers' perspective.

General Guidelines
(Interim Final, 70 FR 15169, March 24, 2005)

In this section API provides further general comments on the Interim Final General Guidelines, and the table below lists observations and recommendations to the cited sections of the FR notice.

General Comments

- API is pleased that the U.S. DOE has cited the **API Compendium** as part of its inventory guidance and supports the use of the methodology therein for the oil & gas industry and other industry sectors at large. The citation should be amended to reference the latest revision of the API Compendium (February 2004), which is different from the April 2001 "road test" currently referenced in the Draft Technical Guidelines.

- The definition on pages 54-55 used for **sequestration** is too narrow and pertains only to carbon capture from the atmosphere. It ought to be modified in line with the definition presented during the April 26 plenary of the public workshop (slide 38) that states, "Sequestration: Long term removal (or prevention of release) CO2 from (into) the atmosphere by biological or physical processes." In this way the definition incorporates both sequestration by the terrestrial biosphere as well as direct **carbon capture** (prior to being emitted to the atmosphere) followed by **CO_2 storage in geological formations**.

- The General Guidelines should incorporate a reference to the **role of combined heat and power** installations and recognize them as either "**avoided emissions**" or as having the potential for **exporting power** that could balance out the import of "indirect emissions" by reporting entities.

- The General Guidelines should allow for independent **3rd party reviewers** to verify the validity of the emissions estimation and the emission factors used in lieu of the mandatory **average quality rating** of 3.0 for enabling registration of GHG emission reductions.

The table below provides specific comments by section:

Section	Comments	Recommendations
§ 300.1 General	▪ The General Guidelines are confusing and potentially unlawful in that they purport to be both "guidance" for "voluntary" reporting and "regulations" that impose many substantive regulatory requirements, even though DOE has no statutory authority to adopt such substantive rules here ▪ The incorporation by reference in §§ 300.1(c) and 300.13 of the Draft Technical Guidelines raises the same questions as to whether they are non-binding or binding	▪ Need further clarification on the voluntary nature of the program ▪ DOE should address the inherent conflict in this "quasi-regulatory" program and either declare explicitly that the General Guidelines is a no substantive, procedural "rule" or non-binding guidance ▪ DOE should do the same for the Technical Guidelines incorporated by reference in the General Guidelines

§ 300.2 Definitions	▪ Avoided emissions: definition should specifically recognize the role of CHP plants ▪ Entity: definition might be problematic due to the different legal structure of companies and their operating divisions ▪ GHG: Listing of element 7 in the definition of GHG (70 FR 15183) is too broad and overreaching. ▪ Sequestration: refers only to removal of CO2 from the atmosphere and not capture and geologic storage	Proposed language for revised definitions: ▪ *"Avoided Emissions* means the emissions displaced by increases in the generation, cogeneration and sale of electricity…" ▪ *"Sequestration* means long term removal (or prevention of release) of CO2 (carbon dioxide) from (into) the atmosphere by biological or physical processes"
§ 300.3 Guidance for Defining and Naming the Reporting Entity	▪ Potential confusion between subsection (b) and 300.7 (b)(1). In the former, "entities" are encouraged, but not required, to define themselves at the highest level of aggregation; while in the latter, entity-wide emission reporting is a prerequisite to registering emission reductions	▪ The Guidelines intermingle the terms entity and subentity, which might create confusion. API recommends that DOE clarify that whatever level of aggregation is chosen, that it is the "entity" that must report its entity-wide emissions.
§ 300.4 Selecting Organizational Boundaries	▪ The preferred use of financial control is not clear; financial controls are a variant of operational control that is more frequently used in GHG guidance.	▪ Recommend that terminology from the Petroleum Industry Guidelines for Reporting Greenhouse Gas Emissions be used.
§ 300.5 Submission of an Entity Statement	▪ In (d)(2), the optional use of the simplified emissions inventory tool (SEIT) is judged not to have a high enough quality for reporting – so what is the use of making it available? ▪ In (d)(9), the requirement that the certifier provide a certification that direct GHG emissions from sources owned or operated by multiple entities are not filed by other entities could be impractical in some cases, since one entity does not always have access to or the right to see another entity's records. However, sec. 300.10(c)(1) apparently requires only that the certifier make a reasonable effort to determine if another entity has reported some or all of the same emissions under 1605(b).	▪ Recommend that the text clarify that SEIT is best used for documenting either the insignificance of emission sources or by small entities that do not wish to register GHG emission reductions ▪ Recommend clarifying that the language requiring that certification be according to the "best of the certifier's knowledge" means only that the certifiers have used some reasonable efforts to avoid double counting, per §300.10(c)(1), although there is no need to expressly certify that such efforts were made.

§ 300.6 Emissions Inventories	▪ In (b) the requirement for using inventory methods with a quality rating of 3.0 or more for entities that intend to register emission reductions is not consistent with current practices with many of the emission factors provided by DOE for many industry sectors. ▪ In (h) the requirement for separate reporting of emissions outside of the U.S. by country of origin might not be consistent with a company's business structure and/or entity definition. ▪ In (j) the requirement to use the GWP from the IPCC third assessment report is inconsistent with current global practices that use the values from the second assessment report for GHG emissions through 2012.	▪ Recommend allowing an option for independent reviewers to assess the quality of information rather than a blunt cut at a 3.0 rating ▪ Recommend re-evaluating this approach since the extra burden might deter companies from voluntary reporting ▪ Recommend providing both sets of GWP values and indicating the expected change after 2012
§ 300.7 Net Entity-Wide Emission Reductions	▪ The requirement for entity-wide reporting (at whatever level of aggregation is chosen to define the entity) as a prerequisite to registering emission reductions needs to be clarified to avoid confusion on what constitutes an "entity-wide" report.	▪ See comment above about the inconsistency of using the terms entity and subentity throughout
§ 300.8 Calculating Emission Reductions	▪ In (h)(2), the requirement of certifying that emission reductions are not attributable to changes in output or major shifts of products and services requires further clarifications. ▪ In 300.8(i) the encouragement to include information on costs, benefits and rate of return of actions taken goes beyond the scope of a GHG registry.	▪ Recommend that the General Guidelines address the differences between emission reductions that are based on emissions intensity vs. those that are based on absolute emissions. ▪ The encouragement to include costs, benefits and rate of return should be removed to prevent the impression that reports are expected to include this information.
§ 300.9 Reporting and Recordkeeping Requirements	▪ In (b), some of the requirements to document changes are onerous and disregard considerations for the significance of the changes made and their impact on the calculated baseline	▪ Amend these requirements to lessen the burden on the reporting entity ▪ Entities could be advised to have all the information on hand for independent review but not necessarily to report it with its GHG emissions report
§ 300.10 Certification of Reports	▪ In (a), support DOE in expanding the list of company officers that can certify the report, provided that these remain options and that the entity can choose which officer should do it	▪ Should consider expanding the list of company officers from which an entity can choose someone to certify the report. Such a list might include the company officer that is accountable for implementing the company's climate change policy

§ 300.11 Independent Verification	▪ Independent verification should not be described only in terms of 3rd party verification. There is precedent in other voluntary management system standards for expanding the realm of what constitutes an "independent verification." ▪ Does DOE intend for the reports to be verified prior to submission on July 1st of the year following the inventory year?	▪ Recommend that DOE allow 1st or 2nd party verification, provided the verifiers are organizationally independent from the entity verified and they meet the qualifications requirements. ▪ DOE should clarify that companies can conduct third-party verifications on a 2-3-year rotating schedule for increased efficiency and cost-effectiveness. ▪ The guidelines need to clarify the timeline for verification of reports.
§ 300.12 Acceptance of Reports and Registration of Entity Emission Reductions	▪ The section does not provide the needed sequence of reporting and verification stages that lead to ultimate DOE approval of the report.	▪ DOE should provide clarifications of the process stages and the timeline expected for reporting and verifying reports ahead of registration.
§ 300.13 Incorporation by Reference	▪ This section refers to August 5, 2004 <u>Draft</u> Technical Guidelines; are they the same as those posted on the DOE website on March 21, 2005? ▪ How can DOE incorporate in these "interim final rules" <u>draft</u> Technical Guidelines that are still undergoing review and comment and may be significantly revised? ▪ Does incorporation by reference mean that the Draft Technical Guidelines are effective, together with the General Guidelines, on September 20, 2005, as suggested at 70 FR 15169? What if those Technical Guidelines are still undergoing revision and have not yet been finalized before Sept. 20, 2005? ▪ As discussed above under 300.1, incorporation of the Technical Guidelines raises the same concerns and confusion regarding the voluntary vs. mandatory nature of the General Guidelines	▪ Clarify reference to Draft Technical Guidelines ▪ Clarify status of incorporation of Technical Guidelines if their revision and finalization will go past the planned effective date for finalization of the General Guidelines ▪ As discussed above under 300.1, clarify whether and to what extent the Technical Guidelines are considered non-binding guidance or binding, substantive regulations

Draft Technical Guidelines
(Notice of Availability, 70 FR 15164, March 24, 2005)

In this section, API comments briefly on some of the issues raised by the DOE in its FR notice of availability of the Draft Technical Guidelines. These general observations and comments are followed by tabulation of detailed comments that are linked directly to the appropriate section of the Draft Technical Guidelines.

Emission Inventory Guidelines (Chapter 1)

- **Emissions Rating System -** The emission **quality ratings** seem overly restrictive for many industry sectors, as discussed in the Overarching Issues above. Specifically, the assignment of a **C ratings** to all "default emission factors based on general activity data." For many sectors these are the most common emission estimation approaches used and it would take considerable R&D to develop new entity-specific factors. These situation should be treated in a manner similar to agriculture and forestry sectors, where the guidelines recognize that monitoring and/or development of specific emission factors is not practicable, and assign an 'A' rating.

  Suggested replacement for Table 1.C.11 is provided in Table 1 below:

Table 1. Revised Ratings for Methane and Nitrous Oxide Emissions from Stationary Source Combustion

Computation Method	Rating
CH_4 emission factors for boilers and furnaces from AP-42 for natural gas, diesel, fuel oils, and coal	A
CH_4 emission factors for boilers and furnaces from AP-42 for refinery fuel gas, butane, propane and wood fuel	B
N_2O emission factors for boilers and furnaces from AP-42 for fuel oils	A
N_2O emission factors for boilers and furnaces from AP-42 for fuels other than fuel oils	B
CH_4 emission factors for internal combustion devices from AP-42	B
N_2O emission factors for natural gas-fired engines devices from AP-42	A
N_2O emission factors for natural gas-fired turbines and diesel or gasoline-fired engines from AP-42	B/C

- **Alternative Inventory Methods -** The US DOE has cited the API *Compendium of Greenhouse Gas Emissions Methodologies for the Oil and Gas Industry* (referred to as the API Compendium) as part of its inventory guidance and thus, by reference, supports the use of the methodology therein for the oil & gas industry. API notes that some of the methodologies cited are also applicable for other industry sectors, especially the sections that pertain to combustion emissions, which would be applicable to all industrial, commercial and residential combustion situations.

  Since updating emission estimation methods and relevant emission factors should be an evergreen process, API recommends that the US DOE incorporate the API Compendium by reference as the source of emission factors and estimation methodologies for the oil & gas industry, so as not to require frequent reopening of the Technical Guidance document as emission factors or methodologies change. API will assume responsibility for maintaining/updating the API Compendium.

- **Inventories of Indirect Energy -** The proposed inconsistency in treating indirect CO_2 emissions between the inventory guidance and the emissions reduction guidance is confusing and creates unnecessary burden for the reporting entities. Please see our comments on the issue in the Overarching Issues discussion above.

As noted above, the guidance provided for **indirect** emissions **outside the U.S.** is not adequate. First, the most recent version of the world energy outlook (WEO) report is available only through purchase from IEA. Second, the 2002 WEO states that CO_2 emissions per unit of electricity generated includes CO_2 emissions from heat production. API recommends that DOE adopt the emission factors provided in the API Compendium or develop its own national CO_2, CH_4, and N_2O emission factors for electricity generation only. Further details on the weighted average approach and information sources are provided in the API Compendium (Section B.1.3).

- **Linkage to IPCC guidance -** In its 2006 Guidelines for National Greenhouse Gas inventories, the IPCC is providing an option for calculating CO2 emissions by assuming as a 100% conversion of carbon-to-carbon dioxide for combustion sources. Although these guidelines target national inventories, and are not always suitable for "bottoms up" inventory approach, this conservative assumption of carbon oxidation is widely applicable and takes into account the fact that some of the products of incomplete combustion will also eventually be transformed to CO2 at a rate that is determined by their atmospheric lifetime. The API compendium has also adopted this conservative assumption as its default approach and DOE is urged to consider doing the same.
  Another IPCC report that might be relevant to finalizing Chapter 1 of the Technical Guidelines is the IPCC Special Report on Carbon Sequestration, which is linked to the section in the 2006 IPCC Guidelines for National Greenhouse Gas Inventories on the same topic. It provides further insight and specific information on inventories of emissions from carbon sequestration projects.

- **Formatting/Editorial -** There are some inconsistencies in formatting and numbering of equations in the document, as well as inconsistencies in the units used in some of the equations. API suggests revising the guidelines to ensure that consistent formatting and numbering of equations are used throughout the document, and verifying that equations are provided in units that are consistent with the resulting term and with overall reporting requirements as spelled out in the Technical Guidelines.

Emission Reduction Guidelines (Chapter 2)

- **Base periods and base values -** Due to the complexity of setting base periods and base values in a changing business climate (mergers, acquisitions, divestitures, changes in processes, changes in products) flexibility in development and modification of base period and base values is very important to development of a meaningful, useful and practical inventory and registry system.

- **Guidance for GHG reductions from specific actions -** Additional guidance, or a set of examples, is needed for estimating GHG reductions from other specific actions. These activities may include: energy efficiency enhancements, increased use of less emissions intensive materials in production processes, or energy conservation campaigns.

  One particular class of specific actions that requires further attention is the emerging uses of carbon capture and geologic storage practices. ***Attachment A*** provides two examples of the potential for GHG emission reductions from two such specific actions: e.g. enhanced coal-bed methane production (ECBM) and enhanced oil recovery (EOR).

- **Combined Heat and Power (CHP), and Thermal Energy Generators -** DOE correctly states that CHP and thermal energy generators should be able to obtain recognition for reductions that result from a broad range of different actions, including increased generation (since most CHP plants are more efficient than conventional power and heat generation), fuel substitution or improved system performance. The method outlined in the Draft Technical Guidelines on the allocation of CO_2 emissions that are associated with self-generation and **export** of electricity, steam or heat is not consistent with other prevailing guidance (see detailed methods comparison in ***Attachment B***, which contains also an industry emission reductions example associated with CHP). API recommends that further discussion is needed on what might be the most appropriate approach in order to reflect the true emission reduction potential for CHP plants.

Additional preliminary comments on the Draft Technical Guidelines are summarized below:

Section	General Observations	Recommendation
CHAPTER 1 – Emission Inventories		
Part B	▪ **Section 1.B.3.1** (p. 14) states that all greenhouse gas emissions from sources owned and operated by the entity must be reported. This is contradictory to the next paragraph in the same section, which indicates that emissions from some activities or entities can be excluded. Specific exclusion criteria are not provided in this section, which further adds to the ambiguity. The concept of *de minimus* emissions is not discussed in the document until much later in Part F (p. 139).	▪ API suggests introducing the concept of excluding *de Minimis* emissions in Section 1.B.3.1. Also, the first sentence of Section 1.B.3.1 requires rewording to omit the use of “all”. API also recommends that DOE make allowance for industry organizations to determine what might be D*e Minimis* emission sources specific to their sector, as applicable.
	▪ **Section 1B.3.2** (p. 15) states that CO_2 is the most common greenhouse gas. Water is actually the most common greenhouse gas; CO_2 is the most common anthropogenic greenhouse gas	▪ API suggests clarifying the parenthetical statement to “the most common anthropogenic greenhouse gas”.
	▪ **Section 1.B.3.2.1** (p. 16) the term “waste combustion” is described as flaring or burning coke catalyst. Flaring and Coke burn are two different activities. Flaring is mainly relied on for emergency relief purposes. Coke burn is an integral part of the catalytic cracking process, and process equipment is designed to recover heat from this combustion process.	▪ API suggests describing the special situations of flaring separate from coke burn.
	▪ **Sections 1.B.4.4, 1.B.4.5, and 1.B.4.6** – This information is not really relevant for the DOE reporting program. Particularly in section 1.B.4.5, DOE appears to be significantly under estimating the amount of effort required by a company to develop and submit technically sound, valid inventory information every year.	▪ API suggests removing these sections from the Technical Guidelines.
Part C	▪ **Section 1.C.2.3** is titled “Mass Balance”. The equation shown in Section 1.C.2.3 does not appear to be a mass balance approach as described in the text box on p. 35. ▪ The equation shown in **Section 1.C.2.3** includes units of tons associated with the carbon emissions and the emission factor. This is inconsistent with the reporting requirements provided in Section 1.A.5 (metric tons). ▪ The equation shown in **Section 1.C.2.3** implies that	▪ API recommends renaming Section 1.C.2.3 to “General Combustion Approach” to better describe the emission estimation approaches presented. ▪ API suggests revising the units shown for the equation in Section 1.C.2.3 to be metric tons for consistency with the reporting requirements provided in Section 1.A.5. ▪ API recommends including the C to CO_2 conversion in the equation in Section 1.C.2.3

	carbon emissions are equivalent to carbon dioxide emissions. ▪ **Section 1.C.2.3** recommends including a percent oxidation factor to estimate CO_2 emissions. However, no default oxidation factors are provided for fuel oils or LPG in Part C. (Part D does provide a fraction combusted of 99% for petroleum-based transportation fuels.)	since CO_2 is the resultant GHG emitted. ▪ API recommends 100% oxidation of fuel carbon to form CO_2. This eliminates ambiguity in the assignment of oxidation values for different fuel types and does not significantly change the results. ▪
	▪ **Sections 1.C.3 .3 and 1.C.3.4**, respectively, include tables 1.C.7 and 1.C.10 that provide gross heating values in units of Btu per barrel. From reviewing the values provided, it appears that the units should read MMBtu per barrel in Table 1.C.7 and 1000 Btu per barrel in Table 1.C.10	▪ API suggests reviewing the units and values provided in Tables 1.C.7 and 1.C.10 and correcting them as necessary
	▪ **Section 1.C.4** indicates that CEM installations for CH_4 and N_2O emissions are not common, yet the two highest quality ratings for stationary combustion sources are based on CEMs. Default emission factors from multiple sources and of varying data quality are combined in the third estimation approach with a 'C' quality rating ▪ **Section 1.C.4** Table 1.C.12 cites the IPCC Guidelines, which cite outdated versions of AP-42	▪ API recommends removing references to CEM installations from Table 1.C.11, and instead referencing emission factors from the API Compendium, which cites AP-42. Refer to **Attachment C (Table C-1)** for API's **suggested** methods and quality ratings for Table 1.C.11. ▪ API recommends replacing Table 1.C.12 with a summary of the most current AP-42 emission factors.
Part C	▪ **Section 1.C.5.1**, last sentence describes refinery fuel gas as "an explosive safety hazard to be controlled." Since refinery fuel gas is no more hazardous than natural gas, it is inappropriate to characterize it with this phrase. Furthermore, this assertion is irrelevant to the GHG reporting program. ▪ **Section 1.C.5.1**, first bullet, describes refinery fuel gas as a waste product. It is not a waste product. ▪ **Section 1.C.5.1** presents two default emission factors for CO_2 emissions from refinery fuel gas: one from EIA (preferred) and one from API. The Technical Guidelines comment that the EIA factor is preferred because still gas most closely approximates the gas mixture used as feedstock. ▪ **Section 1.C.5.1** states that the "fraction combustion" for flaring refinery fuel gas is 98%. However, the fraction combusted is not discussed in Section 1.C.5.3 – Flaring of Natural Gas or Crude Oil. (Note: the 2004 API Compendium assumes that the fraction of carbon converted to CO_2 is 98% for all flares). The Technical Guidelines document does not provide guidance for estimating non-	▪ API suggests deleting the last sentence of the first paragraph. ▪ API suggests rewording this bullet to remove reference to refinery fuel gas as a waste product. ▪ API recommends that DOE incorporate the API Compendium by reference for any oil & gas industry emission factors. API will take responsibility for maintaining the API Compendium and providing emission factors appropriate to the oil & gas industry, and will evaluate the EIA data for inclusion in the next revision of the Compendium. ▪ API recommends presenting a 98% "fraction combustion" in Section 1.C.5.3 for natural gas or crude oil flaring based on guidance in Section 4.4 of the 2004 API Compendium. ▪ Section 4.4 of the API Compendium describes how to estimate non-combusted CH_4 emission from flares. API suggests citing this guidance.

	combusted CH_4 emissions from flares.	
	▪ **Section 1.C.5.2** describes CO_2 emission estimates for petroleum coke combustion; however, no CO_2 emission factor is provided.	▪ Table 4-1 of the API Compendium provides a CO_2 combustion emission factor for petroleum coke of 102.1 kg/10^6 Btu, HHV. We suggest incorporating this emission factor by reference to the API Compendium.
Part D	▪ **Section 1.D.2.2** is titled “Mass Balance”. The equation shown in Section 1.D.2.2 does not appear to be a mass balance approach as described in the text box on p. 35. ▪ No units are associated with the “carbon emission” result for the equation shown in **Section 1.D.2.2,** while units of tons are associated with the quantity of fuel. This is inconsistent with the reporting requirements provided in Section 1.A.5 (metric tons). ▪ The equation shown in **Section 1.D.2.2** implies that carbon emissions are equivalent to carbon dioxide emissions.	▪ API recommends renaming Section 1.D.2.2 to “General Combustion Approach” to better describe the emission estimation approaches presented. ▪ API suggests revising the units shown for the equation in Section 1.D.2.2 to be metric tons for consistency with the reporting requirements provided in Section 1.A.5. ▪ API recommends including the C to CO_2 conversion in the equation shown in Section 1.D.2.2 since CO_2 is the resulting GHG emission.
	▪ **Section 1.D.2.3** states that mobile source CH_4 and N_2O emission factors are not presented in the guidance document due to the large number of emission factors. Instead, a number of other documents are referenced. The 2004 API Compendium is not included on this list. In addition, highway vehicle CH_4 and N_2O emission factors are provided in Table 1.D.2 (which contradicts the text on page 59 that states mobile source emission factors are not provided).	▪ API suggests revising Section 1.D.2.3 (p. 59) to indicate that some highway vehicle CH_4 and N_2O emission factors are provided later in Section 1.D.3.2.1. API also recommends incorporating the 2004 API Compendium by reference in the list in Section 1.D.2.3 since many oil and gas companies rely on the Compendium for GHG emissions guidance
	▪ **Section 1.D.3.1**, Table 1.D.1 does not indicate if the carbon contents are on a lower or higher heating value basis. ▪ **Section 1.D.3.1**, Table 1.D.1 shows the ethanol carbon content as 0. This may be confusing to some users since ethanol contains carbon.	▪ API suggests indicating whether the carbon contents in Table 1.D.1 are on a higher or lower heating value basis to make sure that there is no confusion. ▪ For clarity, API suggests indicating in a note to the table that the carbon content coefficient is treated as 0 since it is assumed to be a pure biofuel.
	▪ **Table 1.D.3** provides a summary of emission estimation ratings for mobile sources. It is not clear whether the emission factors are based on measured or analytical data for the fuel or if a default emission factor is used.	▪ API suggests providing specific guidance in this table to indicate whether the emission factors are based on measured or analytical data for the fuel or if a default emission factor is used.
Part E	▪ Table 5-20 of the 2004 API Compendium includes emission factors for several chemical processes that are not discussed in the Technical Guidelines, including production of carbon black, ethylene,	▪ API suggests that the Guidelines incorporate by reference the API Compendium emission factors for production of carbon black, ethylene, ethylene dichloride, and styrene

	ethylene dichloride, and styrene. ▪	processes.
	▪ **Section 1.E.4.1.5** Table 1.E.9 assigns a "B" quality rating to the mass balance approach for CO2 emissions from hydrogen production.	▪ Estimates of hydrogen plant emissions based on mass balance should receive a rating of 'A', since this method can achieve accuracy of 95% or higher**.**
	▪ **Section 1.E.4.1.9** provides CO_2 emission factors for methanol production, but does not address CH_4 emissions.	▪ For completeness, API recommends that the Technical Guidelines incorporate by reference the API Compendium CH4 emission factor for methanol production.
	▪ A footnote in **Section 1.E.4.2.2** provides a list of references for information on GHG emissions from the oil and natural gas industries. We believe that the top-down inventory approach provided by IPCC for national inventories is not always relevant to the bottom-up facility-level inventories required by 1605(b). ▪ The "comprehensive approach" described in **Section 1.E.4.2.2** (p. 109) will not be cost-effective and will not be more accurate than current approaches. ▪ The list of fugitive emission sources provided in **Section 1.E.4.2.2** (pp. 108 and 110) is somewhat misleading in that it refers to industry activities. Some emissions from these activities would not fit under the fugitive definition provided in 10 CFR § 300.2, such as tank flashing losses in production, or dehydration and sour gas removal in processing. ▪ Section 1.E.4.2.2 (p. 108) indicates that the majority of emissions from the oil and natural gas industries are fugitive although, in reality, combustion emissions are the most significant ones. For non-combustion sources, vented emissions, based on the industry's definition, are also generally more significant than fugitive emissions. ▪ . Footnote #60 in **Section 1.E.4.2.2**, p. 108, refers to the IPCC classification of flaring emissions as "fugitive". IPCC's definition of fugitive emissions is inconsistent with the definition provided in 10 CFR § 300.2. Flaring is also listed under fugitive emissions on page 110. ▪ **Section 1.E.4.2.2** (p. 110) cites the API Compendium for information on CH_4 and CO_2 emissions from fugitive and vent/stack sources. However, DOE's listing of fugitive sources does not agree with the classifications provided in the Compendium (e.g. flaring, storage tanks, loading,	▪ ▪ API suggests incorporating the API Compendium by reference as the source of emission estimation methodologies for the oil & gas industry. ▪ API recommends incorporating by reference the API Compendium emission source classification for Section 1.E.4.2.2. ▪ API suggests revising the text on page 108 to indicate that combustion emissions are the most significant emissions source in the oil and natural gas industries. We also suggest indicating that for non-combustion sources, vented emissions, based on the industry's definition, are also generally more significant than fugitive emissions. ▪ API suggests removing both the footnote and the reference to non-productive combustion as a fugitive source in the main text. ▪ API believes that where a mass balance approach is based on measured process data, the results should be assigned an "A" quality rating. We suggest revising any quality rating tables and the text accordingly. ▪ It is neither cost-effective nor feasible to directly measure emissions from vents and stacks, or equipment leaks and losses. For the sources listed, the API Compendium provides multiple methodologies for estimating emissions. In many cases, material balance approaches are more feasible for vented sources and as accurate as direct measurement. For fugitive sources, the Compendium cites emission factors acceptable for regulatory reporting that do not require direct measurement.

	and maintenance/turnaround activities). ▪ **Section 1.E.4.2.2** Tables such as Tables 1.E.6, 1.E.9, E.19, 1.E.26, and 1.E.41 assign "B" quality ratings for a mass balance approach. The text on page 111 also states that mass balances generally receive a "B" rating. ▪ **Section 1.E.4.2.2** (p. 111), in the first paragraph states that direct measurements are "most plausible for emissions from point sources … although fugitive emissions can also be estimated by taking direct measurements of equipment leaks and losses. It is neither cost-effective nor feasible to directly measure equipment leaks and losses. Concentration measurements of fugitive emissions can be made, but converting the concentrations into quantifiable emissions is not straightforward process. ▪ **Section 1.E.4.2.2** (p. 111) cite the IPCC manual for mass balance approaches and default emission factors. We believe that the IPCC factors exclude key emission sources and are not relevant to facility-level inventories. Also, page 111 cites AP-42 and EPA's EIIP for emission factors in the oil and gas industries.	▪ API suggests providing additional clarification and a citation for the calibration requirement (comment in brackets) on page 111. ▪ In the paragraph discussing a mass balance approach on p. 111, we strongly recommend replacing the reference to the IPCC manual with a reference to the API Compendium. We believe the API Compendium provides a more comprehensive resource for material balance approaches as related to developing facility-level inventories. Similarly, in the paragraph discussing default emission factors (p. 111), API strongly recommends replacing the reference to the IPCC manual with a reference to the API Compendium. We also suggest removing references to AP-42 and EPA's EIIP, as the Compendium includes emission factors from these sources where appropriate.
	▪ **Section 1.E.4.5**, last paragraph on page 135 – it is misleading to say the carbon dioxide is "usually leaked."	▪ API recommends replacing this sentence to state, "Trace amounts of CO2 fugitive emissions may occur after the point of capture…"
Part F	▪ **Section 1.F.2.2**, Table 1.F.1 contain emissions factors that are nearly five years old. How and when will these emission factors be updated? ▪ Grid based electricity CH_4 and N_2O emission factors are not provided in Part F. While these emissions may be small, reporters will need a quantification method in order to determine if they qualify, in aggregate, with other small sources, as *de minimus*.	▪ API requests clarification on the process and frequency for updating emission factors provided in the Technical Guidelines. ▪ API recommends providing some simple emission factors similar to those shown in Table 1.F.1 for CO_2, such as included in Table B-4 of the 2004 API Compendium.
	▪ **Section 1.F.2.7** (p. 145); in some cases, a facility may be a net importer of electricity in one year, and a net exporter the next year, depending on facility electrical needs and on-site generation capacity.	▪ API requests clarification on how this applies to a facility that generates electricity. There should be provision for reporting both when electricity is imported and exported.
	▪ In **Section 1.F.3** (p. 146) paragraph 3of the text reads, "If only the type of the generating plant is known, default emission rates in Table 1.F.3 can be used". It seems that this sentence should reference Table 1.F.5 instead.	▪ API suggests reviewing the text in Section 1.F.3, page 146, paragraph 3, and correcting the table reference as necessary.
	▪ **Section 1.F.3.1** (p. 148) applies an 'A' rating to default regional or default national emission rates is	▪ API recommends assigning "A" quality ratings for default emission factors approaches where

	inconsistent with lower ratings applied to default factors in other sections, such as combustion ▪ In **section 1.F.3.1** the emission factors presented in Table 1.F.5 are based on a 2003 EIA document, but it is not clear how these emission factors have changed from an earlier 1605(b) document (US Department of Energy, Sector-Specific Issues and Reporting Methodologies Supporting the General Guidelines for the Voluntary Reporting of Greenhouse Gases under Section 1605(b) of the Energy Policy Act of 1992, Volume I, DOE/PO-0028, Washington, D.C. October 1994).	use of these emission factors represents the most common emission estimation approaches used by the industry sector ▪ API suggests adding clarification on how the emission factors presented in Table 1.F.5 have changed from the earlier 1605(b) document.
	▪ The Guidelines document provides a default imported steam CO_2 emission factor of 78.95 kg/MMBtu in **Section 1.F.3.2** (p. 149). The document does not indicate if this emission factor is provided on a fuel input basis or steam/heat energy basis and whether the emission factor is on a higher or lower heating value basis. This issue is of concern since Table 1.F.3 provides steam enthalpy values that can be used with the steam emission factor. ▪ **Section 1.F.3.2** provides an indirect CO_2 steam emission factor, but CH_4 and N_2O emissions are not addressed. While these emissions may be small, reporters will need a quantification method in order to determine if they qualify, in aggregate, with other small sources, as *de Minimis*.	▪ API strongly recommends providing the energy usage and emission factor on the same basis to avoid any calculation errors. We suggest providing the default imported steam CO_2 emission factor in Section 1.F.3.2 on a steam/heat energy basis and on a lower heating value basis, for consistency with Table 1.F.3, and documenting this basis with the emission factor. ▪ API recommends providing CH_4 and N_2O emission factors, such as provided in the 1994 DOE report "Sector-Specific Issues and reporting Methodologies Supporting the General Guidelines for the Voluntary Reporting of Greenhouse Gases under Section 1605(b) of the Energy Policy Act of 1992." ▪ API recommends that the CH_4 and N_2O emission factors might be similar to those included in Section 4.7.2 of the 2004 API Compendium ▪ DOE should consider making provisions of 'once for all' de Minimis analyses.
	▪ There is no example calculation illustrating the CHP allocation method described in **Section 1.F.3.4.1**, which would be helpful. For example, it is unclear whether the basis for the thermal output (variable "$\text{Output}_{\text{thermal}}$") should be an enthalpy balance using the steam properties provided in Table 1.F.3. ▪ **Section 1.F.3.4.1** (p. 153): The assumption of 80% efficiency for steam generation may not be appropriate in all cases, and will lead to overestimation of emissions associated with electricity from cogeneration facilities. Also, this approach is inconsistent with that used in the	▪ An example calculation would be very helpful to illustrate the CHP allocation method described in Section 1.F.3.4.1. ▪ DOE should use an allocation method for co-generated steam and electricity that is consistent with other existing approaches. ▪ API suggests revising the units shown for the equations on page 154 to be metric tons for consistency with the reporting requirements provided in Section 1.A.5. ▪ API suggests that DOE revisit the quality ratings provided on page 154 to be consistent with ratings assigned to other methods for

	WRI/WBCSD, UK Emissions Trading System, and the approaches recommended in the Petroleum Industry Guidelines for Reporting Greenhouse Gas Emissions. ▪ In **section 1.F.3.4.1** the equations shown on page 154 includes units of tons associated with the CHP Plant Emissions. This is inconsistent with the reporting requirements provided in Section 1.A.5 (metric tons). ▪ In **section 1.F.3.4.1** (p.154), the ratings assessment for electricity from cogeneration facilities is inappropriately more rigorous than that from other electricity types.	electricity and steam generation. ▪ API is providing the example in ***Attachment B*** to demonstrate various calculation methods for allocation of GHG emissions for CHP.
Part G	▪ **Section 1.G.2** (p. 157) in addressing reporting requirements the text refers to all CO2 emissions to the atmosphere that occur within the reporter's entity boundary –This needs to be defined to exclude naturally occurring emissions from the site, e.g. near surface processes unrelated to injection ▪ In **section 1.G.2** (p. 157), third paragraph: if carbon dioxide used for enhanced oil recovery would have otherwise been vented, capturing and geologically storing this CO_2 should be allowed as registered GHG emission reduction. For example, CO_2 for enhanced oil recovery may be obtained from the separation processes associated with either hydrogen manufacturing, or production of industrial gases such as helium is normally vented.	▪ API recommends revising this discussion to exclude naturally occurring emissions from the site. ▪ API recommends that where carbon dioxide is recovered and used for enhanced oil recovery, that otherwise would have been vented to the atmosphere, this would represent an emissions reduction.
	▪ **Section 1.G.2.2** (p. 158) Footnote 2 uses the term "harvested". The same term is also repeated on page 161. ▪	▪ API suggested replacing the word "harvested" with "produced".
	▪ In **section 1.G.3** (p. 160) losses from the reservoir should not all be assumed to go to the atmosphere. The reporter can generate a reasonable prediction of what portion of the losses might be emitted to the atmosphere and what would stay in a different part of the geosphere.	▪ API recommends that item (c) in the list of alternatives be placed first, while item (a) should become alternative (c). ▪ API is seeking further clarifications on the monitoring intent; is it an annual event or a continuous process.
	▪ **Section 1.G.5**, toward the bottom of p. 161 – The sentence that states, "It is unlikely that naturally occurring carbon dioxide would be harvested for any other purposes than enhanced resource recovery activities" doesn't seem to be required for the points being made. ▪ **Section 1.G.5** (p.162), first two paragraphs seem to	▪ API recommends deleting the sentence indicated.

	indicate that it is possible to use flow meters to measure the amount of carbon dioxide in the reservoir. A flow meter might be appropriate for measuring quantities stored but would not be an appropriate measurement device for the amounts lost.	
	▪ **Section 1.G.5.2** (p. 162), in the second paragraph it is stated, 'Arriving at the correct inventory of emissions after capture may involve some subtraction to determine the correct amount of carbon dioxide emitted', which is a confusing statement without further clarifications.	▪ API is recommending that DOE provide an example on how such calculations should be performed in order to clarify its intent.
	▪ In Section **1.G.5.3**, Equation 4 on p. 163, it is not possible to measure pipeline input and endpoint accurately enough to discern fugitive emissions. ▪ **Section 1.G.5.3** states the following in reference to the EPA refinery fugitive emission factors: "Those factors serve as the basis of the AP-42 petroleum refinery emission factors and API Compendium of Greenhouse Gas Emissions Estimation Methodologies for the Oil and Gas Industry to estimate fugitive VOC emissions from pipelines." We do not believe that these emission factors from the EPA protocol document are the basis of the AP-42 fugitive emission factors presented in AP-42 Table 5.1-3. In addition, the Compendium did not intend for the refinery emission factors to be used for gas pipelines. ▪ **Section 1.G.5.3** (p. 164) Footnote 5 refers to Table 1-1 of the 1995 EPA fugitive protocols document. There is no Table 1-1 in this EPA document; we believe the authors intended to reference Table 2-2 for the refinery fugitive emission factors. ▪ In **section 1.G.5.3**, The component level emission factors (Table 1.G.3) may be overly detailed given the relative contribution of non-combustion CO_2 emissions associated with CO_2 sequestration. ▪ Equations 4, 5, 6, and 7 in **Section 1.G.5.3** each result in "E_{trans}". This implies that each equation is calculating the same term "E_{trans}". However, the text describes different aspects related to transport emissions. ▪ In **section 1.G.5.3**, equation 8, page 165: It is not possible to measure the amount of carbon dioxide in storage at the beginning or end of a given reporting period, and certainly not with sufficient accuracy to characterize fugitive emissions. The reporter can monitor how much carbon dioxide was	▪ API suggests removing the discussion on determining fugitive emissions from pipeline based on input and endpoint measurements. ▪ API suggests reviewing the fugitive emission factors in AP-42 and correcting the text reference in Section 1.G.5.3 as necessary. Additionally, we recommend replacing the refinery emission factors in Table 1.G.3 with reference to the API Compendium for emission factors more closely related to the aboveground equipment associated with transporting and injecting CO_2 for sequestration. Production segment or transmission segment (includes gas storage) emission factors, as provided in the 2004 API Compendium, are more appropriate than refinery segment emission factors. ▪ API suggests correcting Footnote 5 on page 164. As stated above, API recommends referencing the API Compendium for production segment or transmission segment fugitive emission factors over refining emission factors. ▪ API suggests correcting Equation 7 on page 165 to be consistent with the Compendium. We believe the equation should be: ▪ $E_{CO2} = F_A \times WF_{CO2} \times N$ Where: ECO2 = Emission rate of CO2 from all components of a given type in the streamFA = Average emission factor for the component type from the applicable tables WFCO2 = Average weight fraction of CO2 N = Number of components of the given type in the stream.

	put into storage, and assume it is all stored, unless monitoring data suggests otherwise. ▪ Equations are numbered in Chapter 1 Part G, but not in the earlier Parts. ▪ Page 168: The Rating for post injection seepage is listed as listed as TBD. What is the practical implication for this? Does this mean storage projects cannot yet get credits?	▪ API suggests referencing the API Compendium for a range of estimation approaches (e.g., facility-level and equipment-level emission factors), consistent with the range of approaches provided for the oil and gas industry non-combustion emission sources. The 2004 API Compendium provides a number of emission estimation methods for CH_4 that can be adopted for CO_2. ▪ We recommend reworking the equations to refer to different emission aspects by defining a unique emission result variable for each equation (e.g., E_{tank}, $E_{pipeline}$, $E_{fugitive}$, etc.). ▪ API suggests removing the discussion on determining fugitive emissions from storage based on beginning and ending measurements. ▪ API recommends numbering all equations.

CHAPTER 2 – Emission Reductions		
2.2.2	▪ Section 2.2.2.5 (p. 244) states, “Regardless of the method chosen, the end result will be an estimate of the emission reductions in the form of tons of carbon dioxide (CO_2) equivalent …”. Reporting emission reductions in tons is inconsistent with the requirement to report emission inventories in metric tons. ▪ Page 255, Table 2.2, though labeled “Partial List of Physical Output Measures Currently In Use by NAICS Codes”, doesn’t include oil and/or natural gas production. ▪ Page 255, table 2.2: Pipeline transportation normalization factor should be barrel--miles, rather than barrels. ▪ Page 255, Table 2.2: Due to differences in refinery configurations, crude oil properties and refinery product specifications, refinery throughput may not be an adequate metric for normalization and comparison of refinery emissions.	▪ API suggests revising the units suggested in the text in Section 2.2.2.5 (p. 244) to be metric tons for consistency with the reporting requirements provided in Section 1.A.5. ▪ API suggests adding oil and/or natural gas production to Table 2.2. ▪ API suggests revising the normalization factor for pipeline transport to barrel-miles.
2.4.1.2	▪ Page 253, fourth bullet: The word 'rule' could be misleading.	▪ Instead of 'one subentity rule', this could be called 'One subentity: one output measurement', or something similar.
2.4.3	▪ For heat generation, Section 2.4.3.2.1 provides the benchmark emission value of 78.95 kg/MMBtu. As indicated in previous comments for Part F, additional clarification is needed to indicate if this emission factor is provided on a fuel input basis or steam/heat energy basis and whether the emission factor is on a higher or lower heating value basis.	▪ API suggests providing the default heat generation CO_2 emission factor in Section 2.4.3.2.1 on a steam/heat energy basis and on a lower heating value basis, for consistency with Table 1.F.3, and documenting this basis with the emission factor.

2.4.5.6.3	▪ Page 268, second bullet: Although this applies to carbon dioxide and sequestration, it should be clarified that if carbon dioxide would otherwise be vented, emission reductions could occur. For example if the carbon dioxide vent stream from a hydrogen manufacturing plant is recovered and used in industrial operations, or in production of carbonated beverages, this could be considered an avoided emission, and should be eligible for registration. ▪ Page 268, last bullet is unclear: "Such entities may only register net increases in volume of gas being sequestered.	▪ API suggests further clarification to expand the definition of an emission reduction. ▪ Only net increases can be registered -- an increase relative to what (base period, common practice…)?
2.4.6.3.1	▪ DOE introduces an energy allocation method that differs from other methodologies published by WRI/WBCSD, the California Climate Registry, and the UK Emissions Trading Scheme.	▪ DOE should use an allocation method for cogenerated steam and electricity that is consistent with other existing approaches.

Attachment A

Emission Reduction Examples – Geologic Capture and Storage

The examples below are provided to illustrate how the methods in the US DOE Draft Technical Guidelines would be applied to Oil & Gas industry operations/projects that would result in GHG emission reductions. The examples though hypothetical are based on real-world experience with similar operations.

The examples are structured to allow examination of differences and similarities with other guidance currently used by the industry and to highlight areas where further discussion might be needed to investigate the best approach for practical application of the technical guidance.

Enhanced Coal Bed Methane Production Example

DOE Draft Technical Guidelines – Section 2.4.5.6.1 – are applicable to CH_4 emission reductions associated with fugitive emissions from operating coal mines and not directly applicable to emission reductions associated with the enhanced removal of CH_4 from unmineable coal seams.

Enhanced coal bed methane production (ECBM) is a technique to produce natural gas (CH_4) from deep unmineable coal seams. Use of CO_2 to displace CH_4 provides a storage and GHG reduction opportunity, which is different from merely capturing fugitive CH_4 emissions from a working mine. In ECBM, CO_2 gas can be injected into the coal seam where it preferentially adsorbs to the coal thereby displacing and releasing the trapped CH_4 while sequestering the injected gas. The use of CO_2 accelerates the recovery of CH_4 during ECBM operations. The process results in two or three molecules of CO_2 adsorbed for each molecule of CH_4 released. At the production well, CH_4 is separated, compressed, and transported for sale. Studies indicate that with these methods over 90 percent of the methane gas in place can theoretically be recovered, compared with only 30-70 percent using conventional pressure-depletion production techniques (EPRI, 1999).

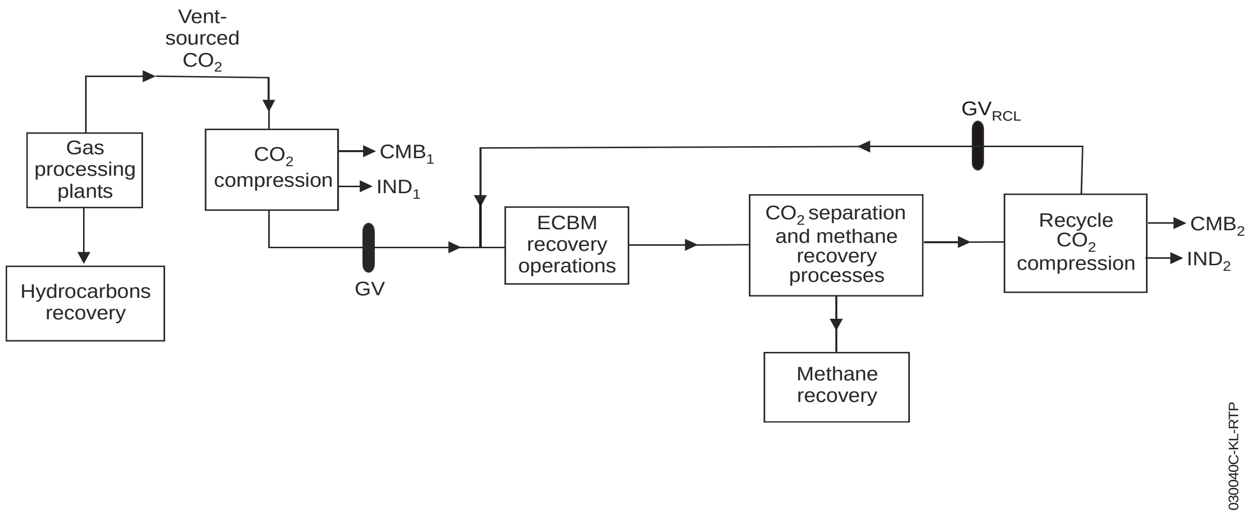
The following example illustrates CO_2 emission reductions associated with enhanced coal-bed methane production.

EXHIBIT A-1: Sequestration of Vent-Sourced CO_2 during ECBM recovery

Vent-sourced CO_2 (98.4 percent CO_2, 1.5 percent CH_4 by volume) obtained from effluent streams of gas processing plants is dehydrated, compressed and metered prior to its use in ECBM recovery operations in unmineable coal fields located in New Mexico. On an annual basis, 2 Bscf of effluent CO_2 is dehydrated and compressed using natural gas-fired engine compressors prior to transport and injection in the coal fields. Fuel and electricity usage at the gas processing and compression facilities are 120 MMscf and 400 MW-hr, respectively. The produced hydrocarbon gas (mainly CH_4) is separated from the other constituents (mainly water and CO_2) and used as fuel or compressed and transported for sale. The CO_2 in the produced gas is dehydrated, compressed using engine-driven compressors, and recycled to the process. Annually, 400 MMscf of CO_2 is recycled using 25 MMscf of fuel in the recycle gas dehydrator and compressor engines. Electricity usage at the recycle facilities total 100 MW-hr/year

EXHIBIT A-1 Continued

A schematic showing the processes and sources of GHG emissions for the CO_2 ECBM sequestration project is provided below.



= Metering Locations
GV = Volume of vent-sourced CO_2 injected for ECBM recovery operations
GV_{RCL} = Volume of CO_2 recycled to process
CMB_1 = Direct emissions from fuel combustion in the vent-sourced CO_2 compression facilities
CMB_2 = Direct emissions from fuel combustion in the recycle CO_2 compression facilities
IND_1 = Indirect emissions from electricity usage at vent-sourced CO_2 compression facilities (equipment, buildings, etc.)
IND_2 = Indirect emissions from energy usage at recycle CO_2 compression facilities (equipment, buildings, etc.)

Schematic of Processes and Sources of Greenhouse Gas Emissions for Vent-Sourced ECBM Recovery Case Study

Baseline Emissions Calculations
Baseline emissions = GV = Gross volume of vent-sourced CO_2 captured and supplied for ECBM (converted to tonnes of CO_2 Eq. per year)

The gross gas volumes (converted from Bscf/yr to tonnes/yr) are calculated as the CO_2 Eq. metered prior to injection. The CO_2 and CH_4 concentrations in the gas were determined to be 98.4 and 1.5 percent by volume, respectively, based on a typical gas composition analysis. A global warming potential (GWP) of 21 was used for CH_4.

$$GV = (\text{Metered volume}) \times [CO_2 \text{ fraction} + (21 \times CH_4 \text{ fraction})]$$

Project Emissions = CMB_1 +IND_1 + CMB_2 + IND_2+ FUG

Where,

CMB_1 = Direct emissions from fuel combustion used for vent-sourced CO_2 processing and compression (tonnes of CO_2 Eq.). Combustion emissions (CMB_1) are calculated based on measured fuel consumption rates and fuel analysis data.

IND_1 = Indirect emissions from electricity usage at the vent-sourced CO_2 dehydrator and compressor engine facilities (tonnes of CO_2 Eq.). These emissions are calculated from regional emission factors and actual electricity usage data as reflected in the electric utility bills.

CMB_2 = Direct emissions from fuel combustion used for recycle CO_2 processing and compression (tonnes of CO_2 Eq.).

IND_2 = Indirect emissions from electricity usage at the recycle CO_2 dehydrator and compressor engine facilities (tonnes of CO_2 Eq.).

FUG = Fugitive and vented emissions from valves, fittings, etc.

Fugitive losses that occur upstream of the vent-sourced CO_2 gas metering location(s) would already be accounted for in the metered volumes. Fugitive emissions from equipment leaks are extremely small (less than 0.03 percent of injected volumes) and therefore, neglected. Losses due to venting (intentional and unintentional) are assumed to be about 3 percent of injected volumes; these are included in the emission calculations.

Project Emissions = CMB_1 + IND_1 + CMB_2 + IND_2 + FUG
= 8,167 + 368 + 1,701 + 92 + 3,468
= 13,796 tonnes CO_2 Eq.

Emission Reductions = Baseline Emissions – Project Emissions
= 115,607 – 13,796
= **101,811 tonnes CO_2 Eq. per year**

Geologic Sequestration Example

DOE Draft Technical Guidelines – Section 2.4.5.6.3 – Storage of CO2 from anthropogenic sources otherwise released into the atmosphere

DOE proposes requiring a life-cycle analysis of losses from sequestration over the next 100 years based on the project abandonment technique or active monitoring of CO_2 losses. Issues related to leakage are the subjects of ongoing research programs. Real reductions in greenhouse gas emissions can still occur through geologic sequestration, and can be quantified on a year-to-year basis using actual operating conditions, without the need to predict events during the next 100 years or potentially expensive, undefined monitoring requirements. The following example illustrates one very specific such project activity, out of a broader range of geological sequestration opportunities.

EXHIBIT A-2: Capture and Sequestration of Vent-Sourced CO_2

One method of enhanced oil recovery (EOR) uses compressed CO_2 to increase the production of crude oil. The CO_2 used in EOR operations can come from many sources, including naturally occurring underground-sourced CO_2, as well as CO_2 captured from vent stacks from gas processing or hydrogen production. Emission reductions occur where previously vented CO_2 is captured, compressed, injected for EOR operations, and ultimately stored in the reservoir.

The baseline scenario for this example consists of carbon dioxide produced from a naturally occurring underground source in the western U.S. that is compressed and transported to EOR sites located in West Texas. By implementing the project, this source of CO_2 is replaced withCO_2 that was previously vented to the atmosphere, as allowed under the terms of existing State and Federal laws, from several gas processing plants located near the main CO_2 pipeline used to transport the underground-sourced CO_2.

The vent-sourced CO_2 (98.4 percent CO_2, 1.5 percent CH_4 by volume) obtained post-project from four gas processing plants is dehydrated, compressed, and metered prior to its use in EOR operations in oil fields located in West Texas. Several engine-driven compressors and electric-drive pumps are used to compress and transport the gas to the EOR sites. Facility fuel and electricity usage records, and CO_2 metering records indicate that, on an annual basis, 1,120 MMscf of fuel gas and 4.82 GW-hr of electricity are consumed at the compression and metering facilities to compress 18 Bscf of vent-sourced CO_2 that is sequestered during EOR operations.

The implementation of this project results in the sequestration of CO_2 that would otherwise be discharged to the atmosphere. EOR operations are continued by substituting a previously vented CO_2 stream in place of an equivalent quantity of underground-sourced CO_2

A schematic showing the processes and sources of GHG emissions for the recycle CO_2 sequestration project follows.

Baseline Emissions Calculations

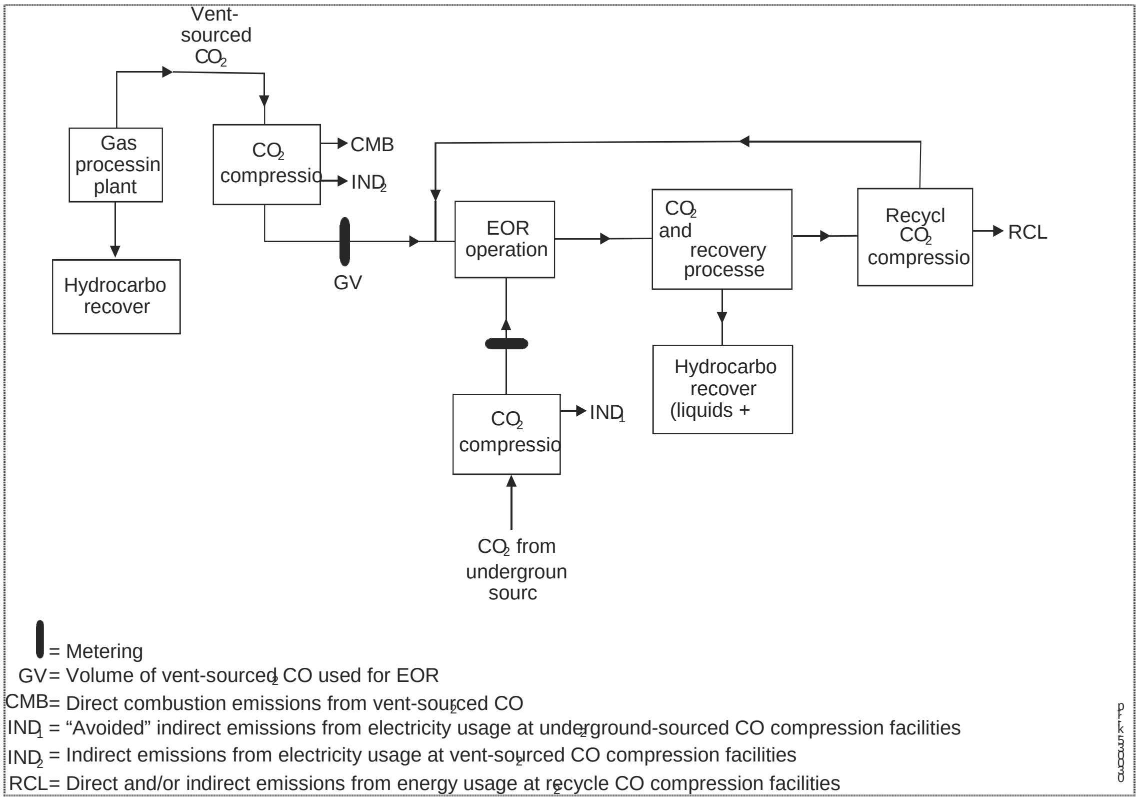
Baseline emissions = GV + IND_1
Where,

= Gross volume of vent-stack gas captured and supplied for EOR (converted to tonnes of CO_2e per year) based on metered volumes.

= Indirect emissions that would have occurred from electricity usage to compress the underground-sourced CO_2 for transport to EOR sites (tonnes of CO_2 Eq. per year). Emissions are calculated based on pre-project energy usage rates and regional grid emission factors.

Baseline emissions = 1,053,094 tonnes CO_2 Eq.

EXHIBIT A-2 (Continued)



Schematic of Processes and Sources of Greenhouse Gas Emissions for Vent-Sourced CO_2-EOR Sequestration Case Study

Project Emissions Calculations

Project Emissions = CMB + IND_2 + FUG + RCL

Where,

CMB = Direct emissions from combustion of fuel in the compressor engines (tonnes of CO_2 Eq.) calculated based on measured fuel consumption rates and fuel analysis data.

IND_2 = Indirect emissions from electricity usage at the compression facilities (tonnes of CO_2 Eq.). These emissions are calculated from actual electricity usage data as reflected in the electric utility bills and regional grid emission factors.

EXHIBIT A-2 (Continued)

FUG = Fugitive emissions from valves, fittings, etc. (tonnes of CO_2 Eq.). Fugitive losses that occur upstream of the vent-sourced CO_2 gas metering location(s) would already be accounted for in the metered volumes. Fugitive emissions would have occurred even in the absence of the project, because the EOR site operators would have obtained CO_2 from underground sources and injected it using the same equipment at the EOR sites. Therefore, fugitive emissions are not included in the calculation of emission reductions, as fugitive losses that occur during the project operations are considered similar to baseline operations, and offset each other.

RCL = Direct emissions from recycle engine compressors (tonnes of CO_2 Eq.). A similar quantity of fuel and/or electricity would be consumed by the recycle compressors to re-compress the underground-sourced CO_2 that would have been used instead of vent-sourced CO_2 to sustain EOR operations. Because emissions from recycle operations during post-project conditions are offset by similar baseline emissions, recycle emissions are not included in the calculation of emission reductions.

Project Emissions = CMB + IND_2 + FUG + RCL
= 76,219 + 3,210 + 0 + 0 = 79,429 tonnes CO_2e per year

Emission Reductions = Baseline Emissions – Project Emissions
= **973,665 tonnes CO_2 Eq. per year**

Attachment B

Emission Reduction Example - Cogeneration

The examples below are provided to illustrate how the methods provided in the US DOE Draft Technical Guidelines would be applied to Oil & Gas industry operations/projects that would result in GHG emission reductions. Although the specific combined heat and power facility is a hypothetical one it is provided to illustrate real-world experience with similar operations.

The examples are structured to allow examination of differences and similarities with other guidance currently used by the industry and to highlight areas where more clarity is needed. It is noted in the guidance below that the method adopted for allocating GHG emissions between the electricity and steam cycle is at the crux of the difference and will greatly impact the GHG emission reduction being calculated by different facilities when employing the different methods cited.

Cogeneration Example

Draft Technical Guidelines – Section 2.4.6.3 – Estimating Emissions Reductions from CHP Generators

As a principle, the magnitude of emission reductions resulting from energy generation (or co-generation) and exports is dependent on the emission intensity of the displaced energy source.

UK Emissions Trading Scheme (DEFRA, 2003), the WRI/WBCSD GHG Protocol Initiative (WRI/WBCSD, 2001), and the California Climate Action Registry (CCAR, 2002) have each published approaches for allocating emissions between energy streams where two or more different parties use these streams. These methods are presented in the API Compendium, although the Compendium makes no recommendation on a referred approach. The DOE Draft Technical Guidelines present another approach. Each of the approaches partitions the total emissions resulting from fuel combustion in the cogeneration unit between the electricity and steam energy streams, but they each use slightly different allocation methods resulting in substantial differences in accounting for emission reductions. The following example illustrates the results associated with each allocation approach for an example cogeneration facility.

EXHIBIT B-1: Energy Allocation Approaches for Exported CHP Electricity and Steam

In this example, a cogeneration facility operates three natural gas-fired combustion turbines, three heat recovery steam generators with supplemental duct firing capability, and a steam turbine. The combustion turbines and duct burners are the only material sources of GHG emissions associated with the cogeneration plant (i.e., fugitive component and vented emissions are assumed to be negligible).

The cogeneration facility consumes 8,131,500 million Btu of natural gas, producing 3,614,000 million Btu steam and 1,100,600 megawatt-hr of electricity (gross) on an annual basis. A nearby refinery purchases 2,710,000 million Btu of steam and 206,000 megawatt-hr of electricity. The cogeneration facility itself requires 38,500 megawatt-hr to operate (Parasitic load) and uses the balance of the steam. The net electricity (856,100 megawatt-hrs, metered at the custody transfer point) is sold to the electric grid.

Using emission factors from the API Compendium (Table 4-1 for CO_2 and Table 4-5 (natural gas turbines) for CH_4 and N_2O), emissions resulting from the combustion of this natural gas = **<u>435,982 tonnes CO_2 Eq.</u>**

The allocation of these emissions among the different energy users is shown in the following table.

Table 1. Comparison of Emission Allocation Approaches

	Emissions (tonnes CO2 Eq) associated with:			
	Refinery			
Efficiency Allocation Approach	**Purchased Electricity**	**Purchased Steam**	**Electricity Sold to Grid**	**Net Cogen Facility Emissions**
DOE Fuel Use $_{Thermal}$ = Output$_{Thermal}$/0.8 Fuel Use $_{Electricity}$ = Fuel Use $_{Total}$ – Fuel Use $_{Thermal}$	36,268	181,626	150,723	67,365
UK ETS $\frac{CO_2 \text{ EF from electricity}}{(\text{lb } CO_2/\text{megawatt-hr})} = \frac{2 \times CO_2 \text{ direct emissions (tonnes } CO_2)}{[2 \times \text{Electricity produced (megawatt-hr)}] + \text{Steam produced (megawatt-hr)}}$ $\frac{CO_2 \text{ EF from steam}}{(\text{lb } CO_2/\text{megawatt-hr})} = \frac{CO_2 \text{ direct emissions (tonnes } CO_2)}{[2 \times \text{Electricity produced (megawatt-hr)}] + \text{Steam produced (megawatt-hr)}}$	55,002	106,410	228,579	42,991
WRI/WBCSD $\text{Emissions}_{Heat} = \text{Emissions}_{Total} \times \frac{\frac{\text{Heat Output}}{\text{Efficiency}_{Heat}}}{\frac{\text{Heat Output}}{\text{Efficiency}_{Heat}} + \frac{\text{Electricity Output}}{\text{Efficiency}_{Electricity}}}$ $\text{Emissions}_{Total} = \text{Emissions}_{Heat} + \text{Emissions}_{Electricity}$ **Results shown are for assumed efficiencies of electricity = 24% and steam = 77%**	62,772	75,441	272,601	25,168
California Climate Registry (General Guidelines) $\text{Emissions}_{Heat} = \text{Emissions}_{Total} \times \frac{\text{Net Heat Production}}{\text{Net Heat Production} + \text{Electricity Production}}$ $\text{Emissions}_{Electricty} = \text{Emissions}_{Total} \times \frac{\text{Electricity Production}}{\text{Net Heat Production} + \text{Electricity Production}}$	41,582	160,335	180,580	56,485
Work Potential Approach $\text{Steam work potential (Btu/lb)} = (H_i - H_{ref}) - (T_{ref} + 460) \times (S_i - S_{ref})$ $CO_2 \text{ EF from electricity or steam (tonnes } CO_2/\text{megawatt-hr}) =$ $\frac{CO_2 \text{ direct emissions (tonnes } CO_2/\text{yr})}{\left[\text{Work potential}_{steam}\left(\frac{\text{megawatt-hr}}{\text{yr}}\right) + \text{Work potential}_{electricity}\left(\frac{\text{megawatt-hr}}{\text{yr}}\right)\right]}$	64,890	66,980	269,672	34,470

As shown in Table 1, the DOE allocation approach assigns more emissions to steam, while the Work Potential allocation approach assigns more emissions to electricity. The WRI/WBCSD approach produces results similar to the Work Allocation approach, based on the assumed efficiencies of electricity and steam. However, determining these efficiencies for an actual cogeneration facility is not straightforward. The remaining approaches generally fall between these two methods, and are each based on an assumed, simplified allocation of energy between steam and electricity.

For quantifying emission reductions, it is useful to compare the DOE benchmark emission intensity factors to those provided in the API Compendium. This is shown in Table 2.

Table 2. Emission Intensity Comparison

	Source	**Emission Intensity**	**Comments**
Steam	DOE US Average Benchmark	78.95 kg CO_2/MMBTU = 0.07895 tonnes CO_2/MMBTU	DOE does not indicate if this is CO2 or CO2 Equivalent. Does not indicate if this is HHV or LHV.
	API Compendium	0.0642 tonnes CO_2 Eq/MMBTU (LHV)	Based on 92% efficient natural gas boiler
Electricity	DOE US Average Benchmark	0.59 tonnes CO_2 Eq/MW-hr (*)	Based on the citation, this appears to be a CO_2 factor, not CO_2 Eq.
	API Compendium – US Average	0.609 tonnes CO_2 Eq/MW-hr	2000-2002 average
	API Compendium – Natural Gas Combined Cycle	0.441 tonnes CO_2 Eq/MW-hr	
	API Compendium – Pulverized Coal	0.942 tonnes CO_2 Eq/MW-hr	

Continuing with this example, the following applies DOE's guidance for calculating reductions associated with energy exports and CHP Generators (Sections 2.4.6.1 and 2.4.6.3).

EXHIBIT B-2: Emission Reductions for Exported CHP Electricity and Steam

Step 1 – Determine the fuel consumed by each process

Fuel use $_{Thermal}$ = Output $_{Thermal}$ / 0.8 = 3,614,000 MMBTU $_{Steam\ output}$ / 0.8 = 4,517,500 MMBTU $_{Thermal}$

Fuel use $_{Electricity}$ = Fuel use $_{Total}$ – Fuel use $_{Thermal}$ = 8,131,500 MMBTU $_{Natural\ Gas}$ - 4,517,500 MMBTU $_{Thermal}$ = 3,614,000 MMBTU $_{Electricity}$

Step 2 – Convert fuel use to emissions

Table 1 above shows the resulting allocation of the total emissions (435,982 tonnes CO_2 Eq.) among the various energy streams for each of the five different allocation approaches.

Step 3 – Calculate reductions

Emission reductions are calculated using the equations provided in section 2.4.6 (page 272) of the DOE Draft Technical Guidelines:

Emission Reductions $_{\text{Reduction Year}}$ = Exported Emissions $_{\text{Base Period}}$ +
(Incremental Generation × Benchmark intensity) - Exported Emissions $_{\text{Reduction Year}}$

EXHIBIT B-2 (Continued)

For this example, we will assume that the cogeneration facility is new and did not generate energy in its base period, so all the power and steam produced are considered incremental generation.

Table 3 summarizes the calculated GHG emission reductions that would result using first, the DOE allocation approach, and second the Work Potential allocation approach.

Table 3. Cogeneration Emission Reduction Comparison

	Benchmark Intensity	**Project (*) Intensity**	**Energy Exported**	**GHG Emissions tonnes CO2 Eq**
DOE Allocation Approach				
Refinery Steam	0.07895 tonnes CO_2 Eq./MMBtu	0.067 tonnes CO_2 Eq./MMBtu	2,710,000 MMBTU	32,384
Refinery Electricity	0.59 tonnes CO_2 Eq./MW-hr	0.176 tonnes CO_2 Eq./MW-hr	206,000 MW-hr	85,284
Grid Electricity Export			856,100 MW-hr	354,425
			Total Reduction	**472,094**
Work Potential Allocation Approach				
Refinery Steam	0.07895 tonnes CO_2 Eq./MMBtu	0.0247 tonnes CO_2 Eq./MMBtu	2,710,000 MMBTU	147,018
Refinery Electricity	0.59 tonnes CO_2 Eq./MW-hr	0.315 tonnes CO_2 Eq./MW-hr	206,000 MW-hr	56,560
Grid Electricity Export			856,100 MW-hr	235,418
			Total Reduction	**438,996**

(*) Note: the project intensity values shown are based on using the tonnes CO_2 Eq. emissions shown in Table 1 divided by the corresponding amount of energy exported (either MMBTU or MW-hr).